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Revisiting the Static and Dynamic Temperature Profiles in Geothermal Wells

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ABSTRACT

Static and dynamic measurements of pressure and temperature along geothermal wells are commonplace practices for characterization purposes in the geothermal industry. Such profiles provide good insight regarding the deliverability of the well, location of the upper and lower boundaries of the reservoir / reservoirs and etc. The static temperature profiles, for example, can be used for modeling the natural state of the system through history matching.

In this study a numerical model is developed to study the parameters affecting the dynamic and static temperature profiles in geothermal wells. The model is based on mass and energy balance equations and couples the reservoir with the well and takes into account the heat losses (or gains) to (or from) the surroundings of the well. The model is validated using various analytical models in the literature. Specifically we consider the comparison between the models of Ramey and Hagoort. A synthetic application is provided to identify key parameters that effect temperature distributions during both production and injection operations. In the application we model temperature behavior along the well for the transition from static to dynamic. Further emphasis is also given to the stabilization times. As mentioned earlier, static and dynamic temperature profiles are important given that real static and dynamic conditions are reached. Not having reached actual static or dynamic conditions could lead to wrong characterization of the system. Hence in the synthetic example provided, we also consider the parameters effecting the stabilization times of the temperature profiles.

1. INTRODUCTION

Static and dynamic temperature profiles can provide good insight on fluid related and petrophysical properties of a geothermal reservoir. Static temperature measurements can be used in estimating the well's entry and exit depths to the reservoir. Dynamic temperature measurements, on the other hand, can be used to estimate the additional water entry points and the total heat lost to the formations surrounding the wellbore. Correctly determining the aforementioned temperature and pressure values in their stable state is of utmost importance. Using temperatures that are still in the transition phase in models as stable temperatures could result in mischaracterization and erroneous results.

Fluid flowing in the wellbore is usually at a different temperature than most, if not all, of the formations encountered outside the wellbore. This temperature difference will cause heat transfer between the formation and the fluid. Depending on the flow direction and the flowing fluid's temperature at the start of the flow, the fluid will gain or lose heat to the surrounding formations. In most cases if the operation is production the fluid will be losing heat, inverse is true if the operation is injection.

The problem of wellbore heat transfer has been studied by many authors. Ramey (1962) gave a simple approximate solution to the problem, assuming steady state heat flow due to convection in the wellbore and unsteady state radial heat flow in the formations due to conduction. This work has been cited by many others. A numerical model by Wooley (1980) takes into account the convective nature of flow and considers cases for horizontal wells. Farouq Ali (1981) gives another numerical model that can deal with steam/water mixtures by using momentum, energy and mass balance simultaneously. An iterative procedure for upward/downward movement of steam/water mixtures is given by Durrant and Thambynayagam (1986). Wu and Pruess (1990) have presented an analytical solution that considers heat losses to an arbitrary number of layers with different properties. Ramey's (1962) work has been revisited by Hagoort (2004). In this study it has been stated that Ramey's approximation to the solution and a rigorous solution are in good agreement at late times. However Ramey's model overestimates the temperatures at early transient periods. Using a drift-flux approach Hasan and Kabir (2010) gave a model for two phase flow. Livescu et al. (2010) gave a semi analytical approach where the extension of isothermal wellbore-flow models to non-isothermal cases are presented.

2. SYNTHETIC APPLICATIONS

In this section the model given by Kutun et al. (2014) is used with the aim of analyzing parameters affecting the stabilization times. The model of Kutun et al. (2014) is a numerical model that is capable of coupling reservoir with the well by considering mass balance and energy balance equations. The verification of the model with the models proposed by Ramey (1962) and Hagoort (2004) are given in Kutun et al. (2014). Extending the previous work we focus on injection case for a single reservoir and injection/production cases for a two reservoir system (a shallow reservoir and a deep reservoir). The parameters that are given in Table 1 are used in the analysis, unless otherwise stated.

2.1 Single Reservoir Injection Case

In this section we analyze a single reservoir system subject to injection at a specified temperature. The grids are initialized to temperatures obtained from a linear geothermal gradient of 0.118 °C /m. Pressure initialization in the wellbore has been done using a hydrostatic pressure gradient. The temperature profiles in the wellbore for various time slices are given in Figure 1. The solid line in this figure, representing a time of 1×10^{-6} day, can be assumed as the initial state of the wellbore. As the injection fluid enters the wellbore at 60°C it first loses heat until it encounters formations with temperatures higher than itself. This behavior can be seen from shallow portions the “t=0.01 days” curve in Figure 1. As the time progresses the bottom portions of the well are cooled. The decreasing difference between late time curves shows the asymptotic behavior of the problem. The temperature contour maps, except for the time of 1000 days, of the system can be seen in Figure 2.

Table 1: Well and reservoir properties used in the analysis.

Well radius, m	0.1
Reservoir radius, m	1000
Reservoir permeability, m^2	1×10^{-12}
Reservoir porosity, fraction	0.2
Rock compressibility, bar^{-1}	2.9×10^{-5}
Rock thermal expansion coefficient, $°C^{-1}$	0
Rock density, kg/m^3	1952
Rock specific heat capacity, J/kg-°C	1000
Thermal conductivity of water, J/m-s-°C	0.67
Thermal conductivity of rock, J/m-s-°C	2.92
Depth of reservoir, m	1000
Height of reservoir, m	100
Initial pressure (@ 1050 m), bar	117.85
Initial temperature (@ 1050 m), °C	144.09
Number of grid blocks in r direction	11
Number of grid blocks in z direction	22
Production/Injection rate, kg/s	4.39
Injection Temperature, °C	60.0
Stabilization Criteria (dT/dt), °C/day	0.1

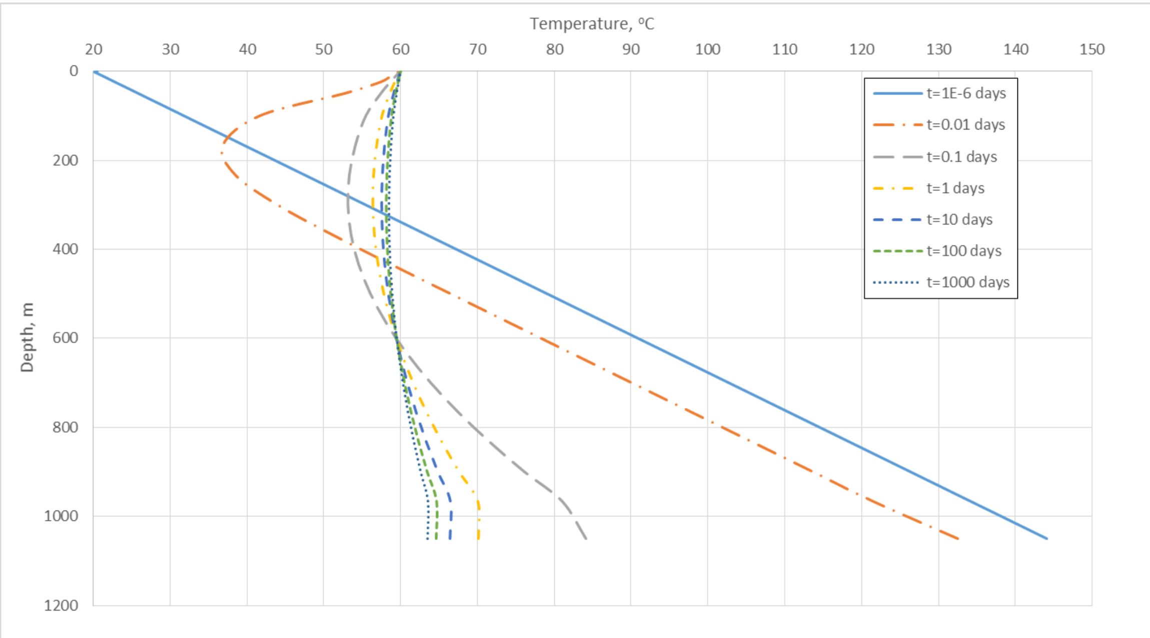

Figure 1: Wellbore temperature profiles of single layer injection case for times of 1E-6, 0.01, 0.1, 1, 10, 100 and 1000 days.

Figure 3 gives the derivative of bottomhole temperature with respect to time. A stabilization criteria of 0.1 °C/day for this case has been considered for bottomhole temperature derivatives with respect to time. In other words it is assumed that the temperature is stabilized once the derivative reaches a value of 0.1 °C/day.

The effects of flow rate is first considered on the stabilization times. Figure 4 illustrates the change of stabilization times with varying flow rate. Increasing flow rates cause a decrease in stabilization times. There are two reasons for this. The first reason is because at lower flow rates it takes a longer time for the hotter fluid to travel to the bottomhole. The second reason is that at lower flow rates, as the fluid is moving towards the bottomhole, more heat is gained from the surroundings of the well, causing the fluid to arrive at the wellhead with higher temperatures compared to what would have been with higher flow rates, hence causing a higher stabilization time.

Taking a look to the effect of changing well radii we see that an increase in wellbore radius causes an increase in stabilization times. This is because, when mass injection rate is kept constant, an increase in well radius translates into lower flow speeds and higher areas available for radial heat flux. The effect of changing wellbore radii can be seen in Figure 5.

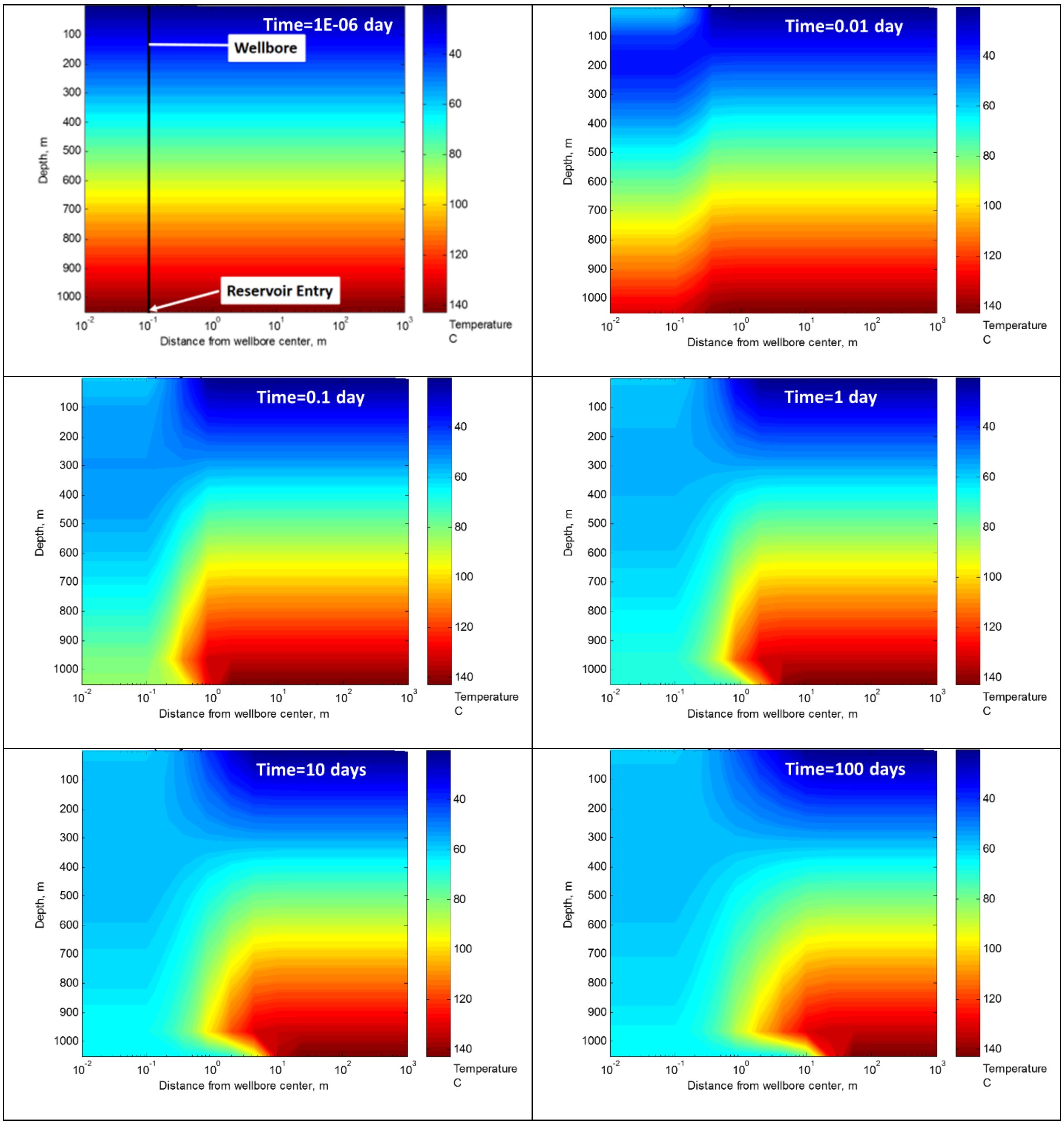

Figure 2: Temperature contour maps of single layer injection case for times of 1×10^{-6}, 0.01, 0.1, 1, 10 and 100 days.

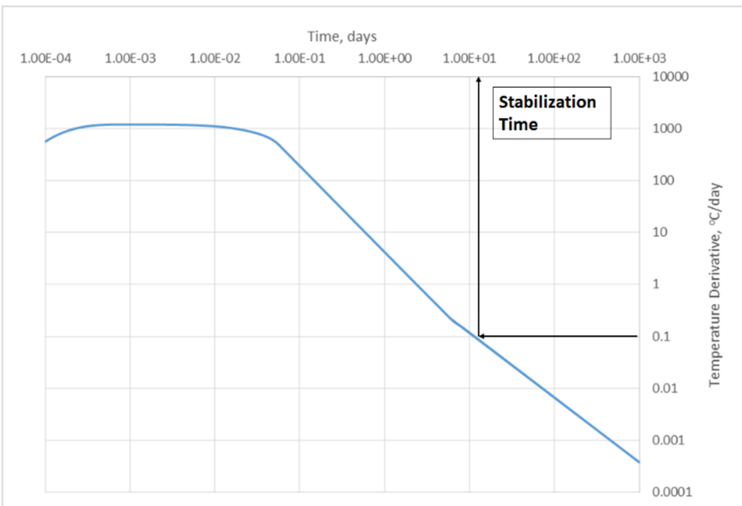

Figure 3: Bottomhole temperature derivative.

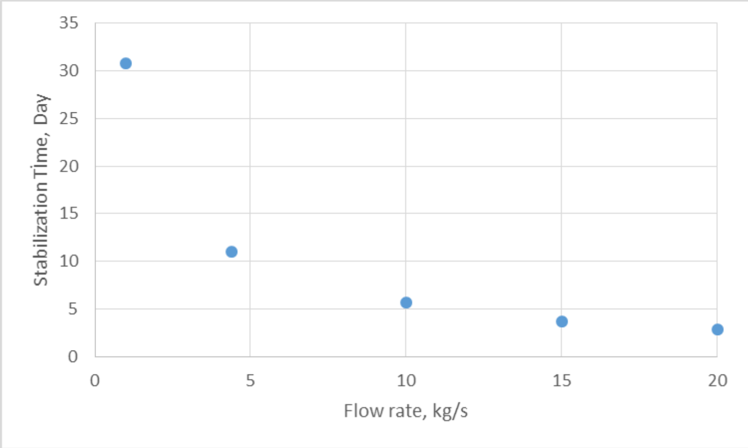

Figure 4: Bottomhole stabilization times for various mass flow rates.

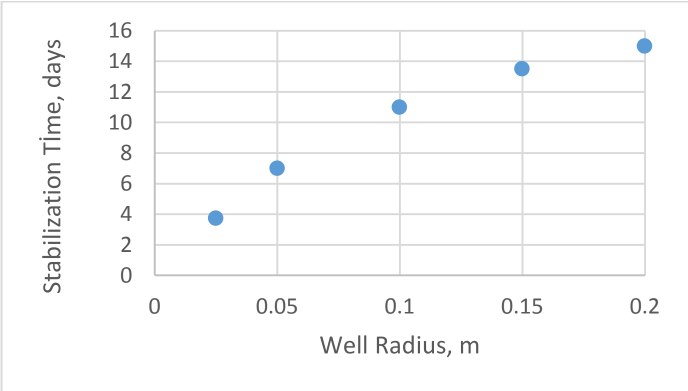

Figure 5: Bottomhole stabilization times for various well radii.

2.2 Two Reservoir Case

Addition of more reservoirs which are connected to the wellbore creates a complicated system. Numerical approximation to temperature distributions and stabilization times are aimed to be determined in this section. Parameters from Table 1 are still valid, additional data and changes are given in Table 2. The grid structure used in modeling the system can be seen in Figure 6. Initialization in this system is done by using 0.124 °C /m geothermal gradient for temperature. Pressure initialization has been done using hydrostatic pressure gradient of water with positive wellhead pressure. We compare the stabilization times for both injection and production cases. For determining the stabilization time for injection, we consider the derivative of temperature with respect to time in the wellbore at the depth of the shallow reservoir. For the production cases, the stabilization times are determined by inspecting the temperature derivative at the wellhead. For both cases, we assume stabilization is reached when the derivatives decrease to a value of 0.1 °C/day.

Table 2: Additional parameters for two reservoir system

Top of shallow reservoir, m	735.7
Initial temperature of shallow reservoir (@760.7 m), ^{o}C	114.2
Initial pressure of shallow reservoir (@760.7 m), bar	170.9
Thickness of shallow reservoir, m	50
Top of deep reservoir, m	1000
Initial temperature of deep reservoir (@1025 m), ^{o}C	146.9
Initial pressure of deep reservoir (@1025m), bar	195.5
Thickness of deep reservoir, m	50
Deep Reservoir permeability, m^2	1×10^{-12}
Shallow Reservoir permeability, m^2	1×10^{-12}

During production, the pressure transient created at the wellhead travels downwards through the wellbore reaching the shallow reservoir first. The shallow reservoir starts contributing to the production while a portion of the pressure transient moves even further down to reach the deeper reservoir which in return starts contributing to the production. The same case is also valid for injection. The temperature profiles of two cases in various time slices can be seen in Figure 8. During production, a different well temperature profile is obtained than that of the single layer case. In the single layer case, the wellbore temperature profile becomes nearly constant at late times during production. However in the case of two reservoirs, we observe two zones in the temperature profile at late times. A hotter zone due to the hotter liquid moving up from the deeper zone (this hot zone is in between the two reservoirs) and a cooler zone above the shallow reservoir. This cooler zone is a result of mixing of the water from the deep reservoir and the shallow reservoir.

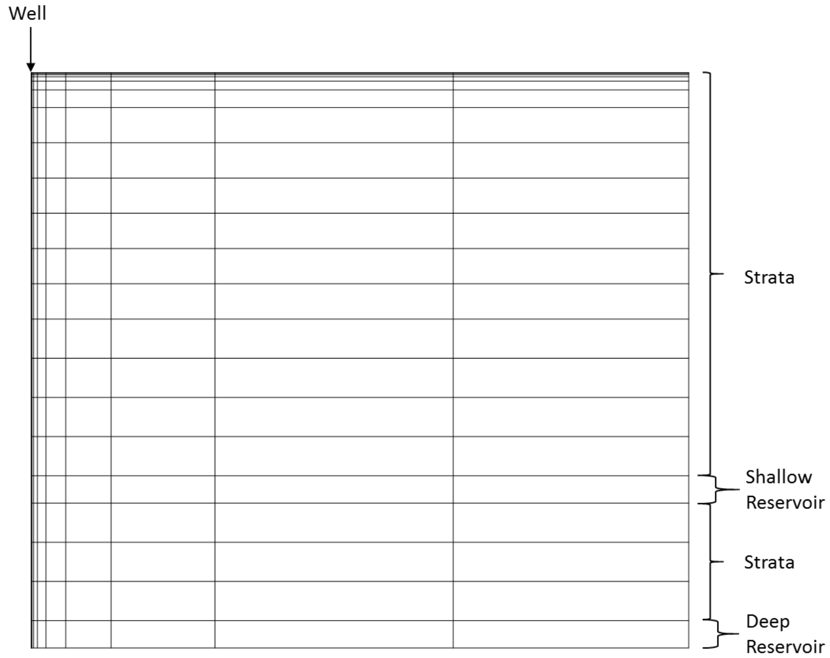

Figure 6: The structure of the grids used in the two layered reservoir cases.

Here we again study the effect of production or injection rate on the stabilization time. Increasing production or injection rates resulted with shortening stabilization times due to the increase in wellbore fluid velocity. This can be seen in Figure 7. Higher velocities allow less time for the fluid-formation couple to transfer heat to each other. This has also been observed previously in the single reservoir case.

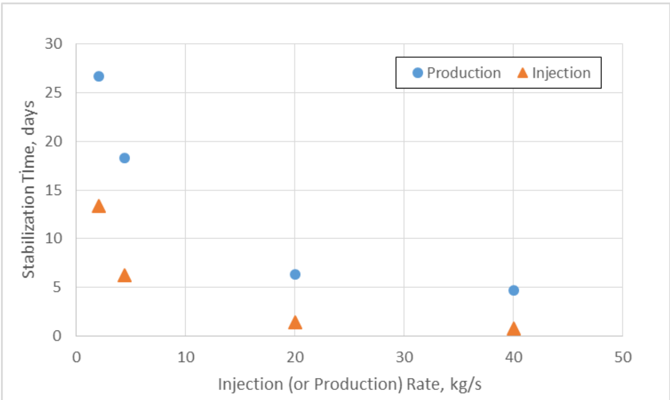

Figure 7: Effect on changing injection/production rate on stabilization time.

Stabilization times of injection cases are shorter than their production counterparts. This is an expected result. The stabilization times during production are determined from the derivative behavior at the well head which is initially assumed to be at a temperature of 20 °C. The initial average temperature of the two reservoirs at the beginning of production is 130.5 °C. The injection on the other hand is performed at 60 °C and the derivative that is considered in the injection case is that of the point in the well at the depth of the shallow reservoir. At this depth the initial temperature is 114.2 °C. Hence, the stabilization times are longer with a temperature difference between 20 °C and 130.5 °C rather than a temperature difference between 60 °C and 114.2 °C.

3. CONCLUSIONS

This work has led to the following conclusions stated below:

- Stabilization times for a single reservoir (considering only injection) and a two reservoir (considering both injection and production) case has been considered in this study.

- In the single reservoir injection case an increase in flowrate has caused a decrease in stabilization times. In the same case increasing well radius has caused an increase in stabilization times.
- In both injection and production cases of the two reservoir system, it has been found that increasing the production or injection rates decrease the stabilization times.

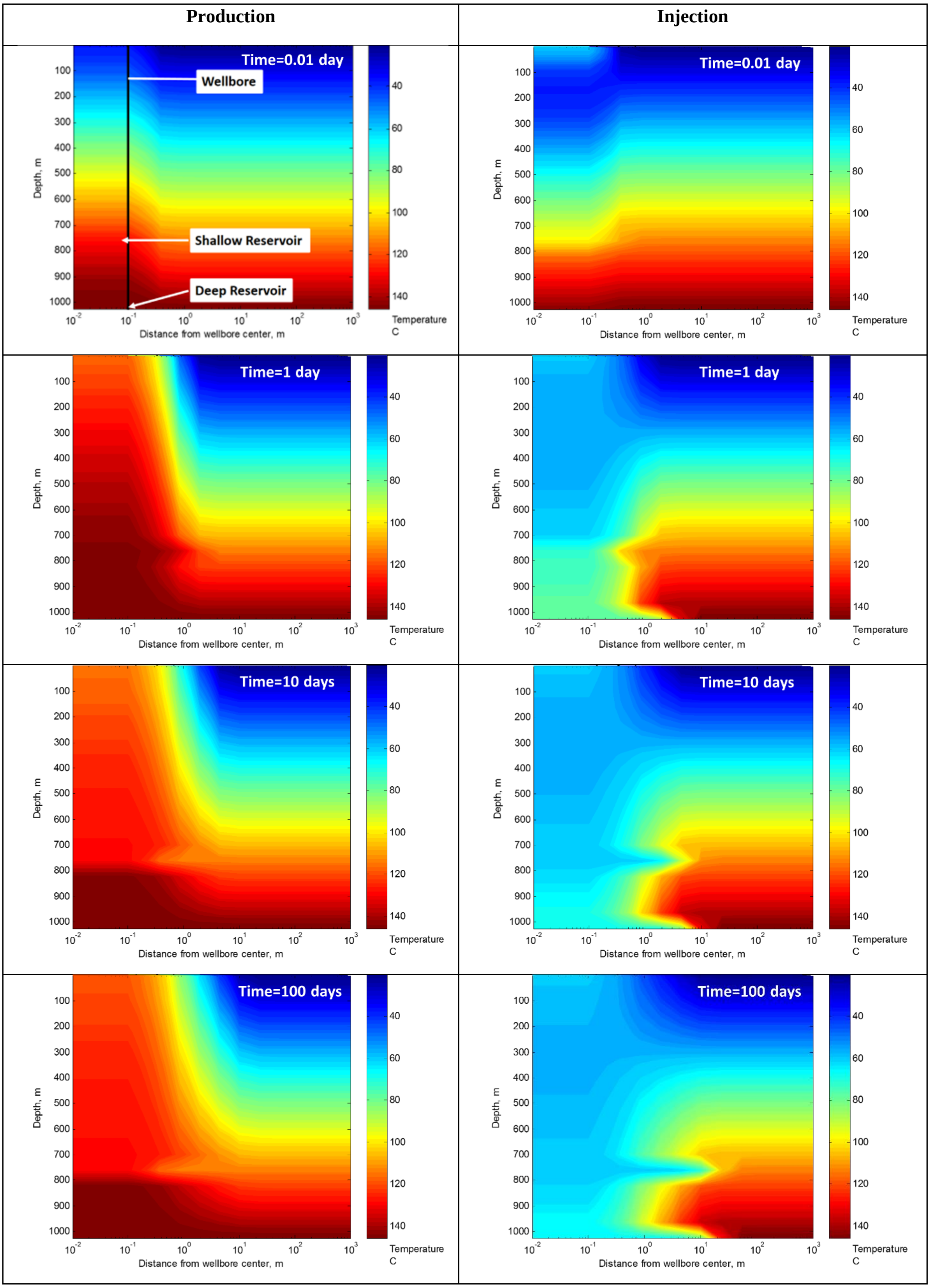

Figure 8: Temperature contour maps of two reservoir system under injection and production cases for times of 0.01, 1, 10 and 100 days.

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